BEFORE THE

WASHINGTON UTILITIES & TRANSPORTATION COMMISSION

DOCKET NO. UE-01_______

EXHIBIT NO. _____ (KON-9)

WITNESS: KELLY O. NORWOOD, AVISTA CORP

July 12, 2000

AVISTA CORPORATION

1997 Integrated Resource Plan Update

I. Introduction:

Avista's last Integrated Resource Plan (IRP) was filed with the Commission on August 25, 1997. That plan showed that the company was surplus for many years into the future. Since then many things have changed in the electric utility industry and for Avista. Therefore, the company has prepared this updated IRP to include those significant changes. As discussed later, this updated IRP will also serve as the basis for a Request- for-Proposal (RFP) that Avista plans to issue.

The following information has been presented at various TAC meetings and will become a integral part of the next IRP.

II. 1997 IRP Update

1. Load Forecast

The 2000 electric sales forecast was prepared during the summer of 1999. The forecast of firm sales to the core-market is one of the most critical elements and was presented and discussed at the TAC meeting. Avista Utilities utilizes econometric models to produce sales and customer forecasts. Econometric models are systems of algebraic equations which relate past economic growth and development in the geographic communities served electricity with past customer growth and consumption.

The electrical energy forecast shows an annual average load of 1013 aMW in 2001 increasing to 1159 aMW in 2009. The peak forecast shows 1594 MW in 2001 with 1851 MW in the year 2009. The ten-year compound growth rate for residential usage is 2.3 percent, commercial is 3.9 percent and industrial is 1.6 percent. The overall total energy forecast has a compound growth rate of 1.9 percent.

The annual load forecast numbers, for both peak and energy, through the year 2009 can be found on the Requirements and Resources tabulation sheet.

2. Resource Assessment

<u>Centralia</u>:
The sale of the Centralia coal-fired plant resulted in the loss of 201 MW of capacity and 177 aMW of annual energy from Avista's resource portfolio. The company entered into a short-term contract with TransAlta, the new owners of Centralia, to replace a majority of the generation lost with the sale of the plant. The term of this contract starts in July 2000 and extends through December 2003.

Hydro Relicensing:
Avista Corp. was granted by the FERC on Feb. 23, 2000, a new 45-year license to operate the Noxon Rapids and Cabinet Gorge hydroelectric projects on the lower Clark Fork River. The licensing effort culminates seven years of planning and consultation, utilizing a unique collaborative approach that produced one of the most successful ever hydro relicensing efforts. The application to relicense was submitted by Avista Corp., Feb. 18, 1999, and contained a comprehensive settlement agreement with 27 signatories.

This landmark agreement ensured the continued economical operation of the two plants while providing a variety of enhancements to natural resources of the project area. Avista retains nearly all the valuable load following and peaking capability of the two projects while providing early implementation of protection, mitigation, and enhancement measures to benefit native fish species, recreation opportunities, continued protection of cultural resources, wildlife populations, and water quality. Avista will spend approximately $4.7 million annually with a significant expenditure earmarked for enhancing bull trout populations.

Contract Sales and Purchases:
While there has been a lot of wholesale contract activity since the last report, the terms of the more recent contracts have tended to be relatively short. It is interesting to note that most of the purchase and sale agreements terminate by the year 2003, except some of the contracts with BPA and exchanges. There are only three sale contracts that extend beyond the year 2003. Those are the PacifiCorp, PGE and Snohomish PUD contracts.

> *PacifiCorp and the company entered into a ten year summer capacity sale for the period June 16, 1994 through September 15, 2003 (with PacifiCorp option to extend for up to five years). The company delivers 150 MW of summer capacity with energy purchased at 25 percent load factor based on variable prices.
>
> *Portland General Electric is purchasing from the company 150 MW of capacity through December 31, 2016. The energy associated with the capacity deliveries has to be returned within 168 hours.
>
> *Snohomish PUD purchases 100 MW of firm capacity with a minimum amount of firm energy at 50 percent load factor from the company. The contract ends September 2006.

Avista also has a large cogeneration facility (Potlatch Forest Industry) in its service territory that entered into a ten-year contract with the company which terminates at the end of 2001. The power received from Potlatch has a maximum capacity of 59 MW and average energy of 55 aMW.

Hydro Upgrades:
In 1999, the company completed the program to replace all four runners at Long Lake, which increased the capability from 72.8 MW to 88 MW. In the planning stages are turbine runner replacements and generator rewinds for three units at Cabinet Gorge and two units at Noxon Rapids. There is also a possibility of an Upper Falls turbine runner replacement and generator rewinds for three units at Little Falls.

3. Reserves Analysis

A reasonable level of planning reserves helps the company ensure adequate generating capacity during periods of extreme weather or unexpected plant outages. Avista's planning reserves are not based on the size or types of its resources. Avista's capacity reserves include components for cold weather, generator-forced outages and contingencies such as river freeze-up at hydroelectric plants.

The company's planning reserves are based on 10 percent increase in peak loads or one day in twenty years and an additional 90 MW to account for river freeze ups and a portion of the forced outage reserves. This provides Avista with about 15 percent reserves based on forecasted peak loads. The forecasted peak loads are based on the average expected cold day. For example, the peak for January 2000 was estimated at 1557 MW (at 8 degrees F) but we would expect the peak to be 1713 MW on the extreme day (-10 degrees F).

Avista's operating reserves are considered a part of the company's planning reserve numbers. The operating reserves are 5 percent of hydro generation and 7 percent of thermal and are what we are legally required to carry under regional criteria.

4. Re-dispatch Study

As the company contemplates the addition of one or more resources to its portfolio it will be faced with a different resource stack and fuel mix. The new resources will have an impact on the resource dispatch sequence because of the fuel supply and marginal costs. The company is using PROSYM to model its resources, to meet its load requirements on an hourly basis, and to assess the dispatch requirements and compatibility of new resources used in conjunction with existing resources, both hydro and thermal.

PROSYM is a commercially available production cost model used to perform electric planning and operational studies. Due to its hourly chronological design and its capability to accurately dispatch the company's flexible hydro system, we use PROSYM to perform dispatch analyses of various generation sources. A key point to remember is that PROSYM is a production cost model. The resource inputs include machine characteristics, fuel costs, and variable operation and maintenance costs. The model does not calculate the total cost of the resource. After the dispatch information is obtained from PROSYM, traditional economic analyses of each resource option must be performed.

An example of a PROSYM run with a new combined cycle combustion turbine modeled into the company's system is shown in Appendix A.

5. Long Term Natural Gas and Electric Price Forecasts

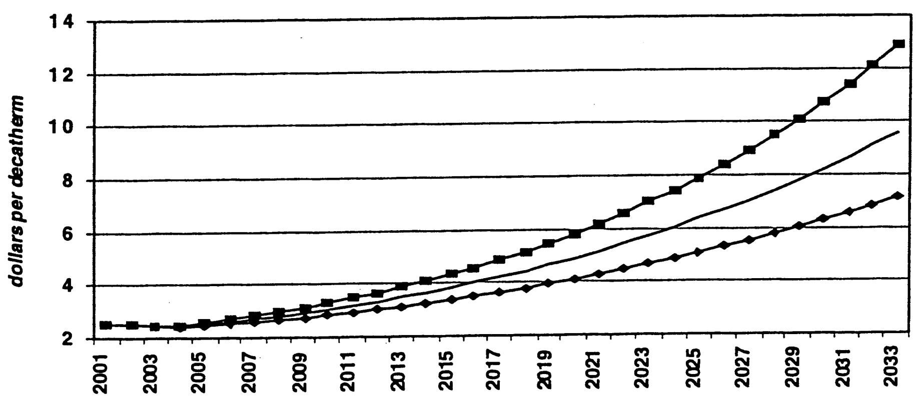
There is much uncertainty in the natural gas and electric price forecasts. Price volatility has increased recently given extremely high prices in the daily and forward markets. The company knows that there will be periods of high prices and periods of low prices as the price curves fluctuate based on demand and supply criteria. It is the company's goal to provide and use a forecast that is reasonable in its start point and escalation for the long term. Avista knows there will be variations both high and low in the future as the company forecasts these energy prices. The forecasts reflect the best information that is available at the time the forecast is made.

Key to any "buy or build" decision is an understanding of the future prices for electricity and natural gas. Because natural gas generation is a significant contributor to the cost of operating such a facility, the future prices for this underlying commodity cannot be overlooked. As discussed above, there is uncertainty in both the near-term and long-term natural gas price forecasts. Avista therefore relies on a set of forward predictions it believes account for a range of possible future outcomes.

The Natural Gas Price Forecast

The price forecasts developed for this update build on the natural gas forecast contained in Avista's forthcoming July, 2000 Natural Gas Integrated Resource Plan (Gas IRP). Contained in the Gas IRP is a base forecast of northwest natural gas prices, as detailed in the median or base case forecast shown below.

Northwest Natural Gas Price Forecasts
2001-2033 nominal dollars



As detailed in the graph in the base case, natural gas prices rise from an average annual value of $2.52 in 2001 to $6.35 per decatherm in 2025, the end of the Gas IRP forecast. On average, this equates to a 4.1 percent annual change.

The Gas IRP does not analyze natural gas price sensitivity at the wholesale level and ends its forecast in 2025. Therefore to represent low and high forecasts, the base case escalation rate was adjusted downward and upward by 1 percent annually, respectively. Additionally, to provide a 30-year forecast beginning in 2004, the rate of change in 2025 was continued through 2033. In the low case, the cost per decatherm rises only to $7.12. In the high case, the price increases to $12.88. This compares to a base forecast in 2033 of $9.60 per decatherm.

The Electricity Price Forecast

With the scenarios for future natural gas prices established, electricity price forecasts was estimated using a "spark spread." Spark spreads identify the heat rate expressed in Btu/kWh that, when applied to a natural gas price, equate an equivalent price of electricity. For example, on June 8, 2000 the forward price for July 2000 natural gas was $4.13 per decatherm. The July 2000 Mid-C forward price was approximately $110 per MWh. The spark spread for July equated to 26,635 Btu/kWh.

The average spark spread through calendar year 2000, again using quotes obtained on June 8 2000, is 21,920 Btu/kWh. Looking forward, the calendar year 2001 spark spread is approximately 17,300 Btu/kWh. To convert the natural gas price forecasts into electricity forecasts, varying spark spread values were considered. The short-term spark spreads inherent in today's forward markets appear high given historical levels. Between 1997 and 1999, the spark spread varied from a low of 7,800 to nearly 17,000 Btu/kWh.

To represent the varying spark spread levels Avista considered three spark spreads of ten, thirteen, and fifteen thousand Btu/kWh applied to the three natural gas price forecasts. At ten thousand Btu/kWh with base case gas prices, electricity prices rise from approximately $24 per MWh in 2004, to $38 per MWh in 2013, to $96 per MWh in 2033. The average annual nominal price increase equals 4.8 percent. In real terms, the equivalent values are $22, $27, and $31, equal to a 1.1 percent annual increase.

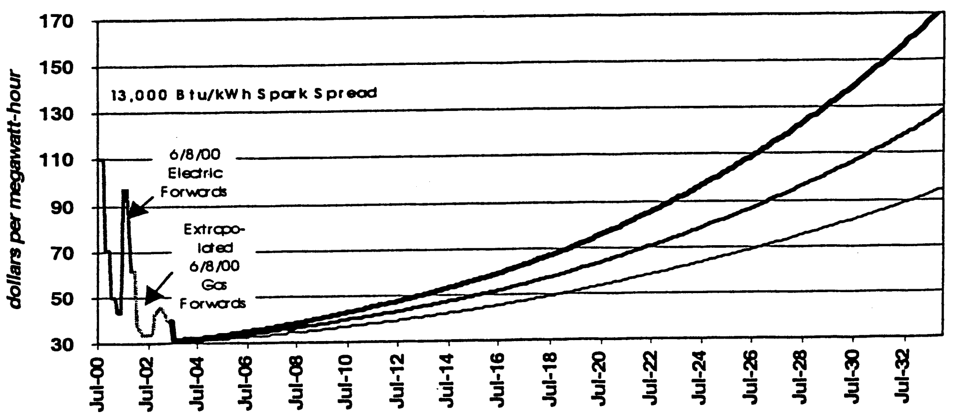
Where the spark spread is assumed to be fifteen thousand Btu/kWh, our high case estimate, electricity prices equal $39 per MWh in 2004. Prices rise to $61 in 2013 and then to $153 in 2033. The average annual price escalation again is 4.8 percent nominal. In real terms, prices rise from $36 in 2004 to $49 in 2033, for an annual average real escalation of approximately 1.1 percent.

Avista's base case spark spread forecast is thirteen thousand Btu/kWh. At this level, electricity prices rise from approximately $32 per MWh in 2004 to $50 per MWh in 2013, to $125 per MWh in 2033 using the base case gas forecast. In real terms, the equivalent values are $29, $35, and $40 per MWh in 2004, 2013, and 2033, respectively. The average nominal increase equals 4.8 percent. In real terms, the forecast rises 1.1 percent annually.

Using the low natural gas price forecast and the base case spark spread, electricity prices rise more slowly at 3.8 percent annually, or 0.1 percent real. In 2004 the annual average electricity price equals $31 per MWh. By 2033 the price equals $93 per MWh. With the high natural gas forecast, electricity prices rise at an average annual rate of 5.8 percent nominal and 2.0 percent real. Forecasted prices increase from $32 per MWh in 2004 to $167 per MWh in 2033.

The following table describes the three electricity price forecasts, including forward market prices prior to August 2003.

Northwest Electricity Price Forecasts
July 2000-2033 nominal dollars



6. Resource Alternatives

There are multitudes of resource options available to the company. Some are more suitable than others depending on capital cost, dispatchability, accessibility, operating experience, environmental considerations, and other impacts. All resource options will be evaluated including energy efficiency measures. Probably the preferred resource scenario will be a combination of resource options.

Some of the options that have been discussed and are under consideration are:

- Build a generating resource
- Purchase existing or new generation assets
- Complete system upgrades at generating facilities
- Negotiate a long-term power purchase agreement
- Buy in the short-term wholesale market
- Purchase the output of a generating or cogeneration facility
- Develop additional energy efficiency and DSM programs
- Buy energy efficiency through third party developers

Customer load dropping is also being considered although it is not generally considered a resource. Retail load that can be interrupted or curtailed under specific circumstances can free-up temporary capacity and energy. And as such, the company plans to explore those possibilities through contract negotiations with large customers.

The initial screening of resource costs uses data from the Power Council, actual sites being constructed or just recently constructed, and information received from national publications.

Attached are the nominal levelized costs in 1999 dollars of many supply-side resource types made available by the Power Council (see Appendix B).

Nuclear plant costs are not on the list, although we know (from previous Power Council studies) that nuclear total cost is above 100 mills/kWh or ranked on the high end of the Power Council's geothermal projects.

Biomass plants are also not on the list except for land fill gas and biogasification plants. The analysis show that biomass plants have total costs in the range of the low geothermal costs or about 70 to 80 mills /kWh.

Many of these resources have costs that are very site specific, especially the renewables like, wind and geothermal. Avista would need to do a very detailed cost analysis based on a particular site location in order to assess ultimate viability of these options.

Avista is constantly assessing the markets in order to buy and sell power on an hourly and daily basis. Most utilities and marketers don't want to commit to long-term sales due to the uncertainty in the markets. At this time other utilities in the Northwest find themselves in the same situation as Avista so a long-term commitment from them for a power supply would not be very likely. We have included in the proposed RFP a provision to bid to Avista a long-term power supply contract.

Avista's energy efficiency programs are evaluated in detail on a trimesterly basis and submitted to the company's External Energy Efficiency (Triple-E) Board for review. These reports cover the full menu of standard practice tests and descriptive statistics and are disaggregated by customer segment and technology. These reports are the basis for company program management efforts as well as providing a foundation for meaningful oversight by the Triple-E Board. The company has also assessed the potential for enhancements to specific programs to meet utility resource needs and will be assessing the potential for capacity and peak-energy targeted programs in the near future. Please see Appendix C for further information.

7. Screening Results

Avista has historically planned and developed various resource types. The company has experience with hydro, coal, natural gas, and biomass generating plants and demand-side resources. This operating experience gives the company valuable information that can be used in its resource evaluations.

Avista needs a resource that can provide additional benefits in support of the existing generation system. What is needed is a resource that can be dispatched, follow load, and provide a capacity component. In other words, as an entity with a control area, the company needs resources that are dispatchable and meets energy and capacity requirements under a variety of conditions.

A natural gas fired electric generation plant is one example of a resource that could meet those needs stated above. Natural gas plants can be built relatively quickly with relatively low capital costs and discharge less pollutants into the air than other fossil fuel plants. As shown in Appendix B, the Northwest Power Planning Council costs for natural gas fired generation projects range from approximately 41 mills to 43 mills.

At this point in time the following resources would not pass the initial screening. The following costs are nominal life-cycle, levelized costs.

- Nuclear: Costs are over the 100 mills per kilowatt-hour range. The total cost and the lack of public acceptance make this resource option unacceptable.
- Coal: Costs are 80 to 90 mills. The total cost and cost uncertainty in air quality issues make this resource option unacceptable.
- Wind: Costs are 60 to 80 mills. There are indications that costs are declining but our studies show there are not favorable sites in our service territory so transmission costs would have to be added. Because wind is intermittent the resource would have to be discounted for lack of capacity component. This would make this resource option unacceptable.
- Geothermal: Costs are 80 to 100 mills making this resource option unacceptable.
- Solar: Costs are over 240 mills making this resource option unacceptable.

These costs are presented for general comparison purposes. The company will solicit resource bids from the market in an upcoming Request-for-Proposals (RFP). The company is hoping for innovative bids from project developers. The RFP bids will be evaluated against the information that has been gathered both internally and externally.

8. Load and Resource Summary

General:
Included is Avista's annual Requirements and Resources (Load and Resource Summary) that shows the company's load and resource position on an annual basis for the next ten years (see Appendix D). It is dated June 1, 2000 and will be the same one used in the 2000 IRP. The peak column is the January peak (the highest forecasted peak for the year) and the average column is the annual 12-month average for the year. The resource peak numbers are what could be expected as maximum capacity outputs during January. The hydro peak and energy numbers are from the final regulation done by the Northwest Power Pool and reflect the reservoir levels in January per the hydro regulation study (one-year critical period, 1936-37 water). The average energy numbers are the expected 12-month averages for the loads, resources and contracts.

All the requirements are shown at the top of the page. Most of the purchases and sales contracts end by the year 2004. The peak and average forecasted loads are shown on line 1 labeled System Load. Line 17 Reserves are Avista's planning reserves and are part of the total Requirements (as described in Section 3).

The Resource section is comprised of the resources and purchase contracts. Line 19 shows the system hydro and line 20 is the contract hydro from the mid-Columbia PUD projects (with critical water conditions). The mid-Columbia numbers decrease due to the Priest Rapids contract ending in 2005 and the Wanapum contract ending in 2009. Avista is hopeful that a contract extension can be negotiated with Grant County PUD. Lines 24 and 25 are the company's existing simple-cycle combustion turbines, and lines 33 and 34 are the expected thermal generation output from Kettle Falls and Colstrip.

Line 29 shows the BPA residential exchange contract and the 47 MW flat delivery of power to the company from BPA. There is no dispatchability or flexibility with this contract. Although this contract has not been signed, Avista feels it is firm enough to be included.

Line 44 is the Surplus (Deficit) numbers calculated by subtracting the Total Requirements from the Total Resource numbers. In the year 2004 Avista is 287 MW deficit on peak and 318 aMW deficit on energy under critical water planning criteria.

<u>Resource Flexibility</u>:
Flexible generation resources are a key component to meet the requirements of Avista's customers. As depicted in the charts on pages 8 and 9 in Appendix E, Avista experiences load changes of 100 MW or more during several hours of each day. Loads must be ramped up and down under a variety of seasonal and load conditions. In order to meet the load, flexible resources (Cabinet Gorge, Noxon Rapids, Long Lake, Mid Columbia contract hydro, and the Rathdrum Combustion turbines) are dispatched. Even with these resources, Avista still must purchase peak energy products to meet customer demand during different times. The market today tends to offer standard heavy load hour and light load hour products that do not meet load shaping or following needs.

<u>2004 Study</u>:
A detailed tabulation of the load and resource requirements study of the year 2004 is also attached (see Appendix E). We chose the year 2004 for an in-depth study because, as mentioned above, many of the larger supply and requirements contracts have ended and future requirements change (for the most part) due to load growth.

This study is shown in two parts. The first study shows on and off peak loads and resource requirements monthly under critical and normal hydro conditions. The second study goes into even further detail. We created an hourly Surplus-Deficiency duration Curve for the year 2004 using PROSYM to gain the following information. By using the Northwest Power Pool's sixty year hydro generation study for our system, PROSYM runs 720 (sixty years X 12 months/year) hydro scenarios into the forecast net system load, all known contracts, and existing resources. The information gained from this model output shows the company's resource requirements to meet load under many different hydro conditions. This duration curve will be used to analyze how new resource additions will "fit" into the company's requirements without any affect from market conditions. As stated before, standard economic modeling must be performed after dispatch information is gained from PROSYM modeling.

Load growth expectations based on the forecasted methodologies are explained under Section 1. Avista doesn't expect drastic changes in our load beyond the normal load growth that has been experienced. But the future is uncertain and Avista needs to be flexible enough to handle unforeseen changes. For example, the company could lose load by having Avista's larger retail customers install cogeneration, like WSU or Potlatch deciding to serve their own load from existing generating facilities. Or if partial deregulation was to come to our region, Avista could pick up some industrial loads thereby increasing the load requirements.

Exhibit D – Annual Load and Resource Forecast

		AVISTA CORP.																			
Requirements and Resources																					
figures in MW		2000		2001		2002		2003		2004		2005		2006		2007		2008		2009	
Line No.	REQUIREMENTS	Pk	Avg	Pk	Avg	Pk	Avg	Pk	Avg	Pk	Avg	Pk	Avg	Pk	Avg	Pk	Avg	Pk	Avg	Pk	Avg
1	System Load	1557	1008	1594	1013	1557	971	1572	982	1608	1007	1649	1033	1692	1059	1743	1091	1796	1124	1851	1159
2	PacifiCorp Exchange	0	3	0	3	0	3	0	3	0	3	0	3	0	3	0	3	0	3	0	3
3	Puget #2	100	75	67	50	33	25	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4	PacifiCorp 1994	0	9	0	9	0	9	0	9	0	9	0	9	0	9	0	9	0	0	0	0
5	PGE #1	150	0	150	0	150	0	150	0	150	0	150	0	150	0	150	0	150	0	150	0
6	Snohomish 10 yr	100	88	100	88	100	88	100	88	100	88	100	88	100	88	0	0	0	0	0	0
7	Cogentrix 57 mo	100	100	100	75	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8	Nichols Pumping	0	7	0	4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9	West Kootenay	125	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10	Eugene Water & Electric	10	5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
11	PGE Sale	25	25	25	25	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12	Pend Oreille	6	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
13	Montana Sale	100	100	100	58	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
14	Duke Sale	100	100	100	58	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
15	Clark2 PUD	250	137	250	85	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
16	City of Cheney	2	2	2	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
17	Reserves	246	0	249	0	246	0	247	0	251	0	255	0	259	0	264	0	270	0	275	0
18	TOTAL REQUIREMENTS	2871	1662	2737	1470	2086	1096	2069	1082	2109	1107	2154	1133	2201	1159	2157	1103	2216	1127	2276	1162
	RESOURCES																				
19	System Hydro	936	313	936	313	936	313	936	313	936	313	936	313	936	313	936	313	936	313	936	313
20	Contract Hydro	195	76	195	76	195	76	195	76	195	76	195	71	140	50	140	50	140	50	140	44
21	Can Ent Return	-10	-5	-10	-5	-10	-5	-10	-5	-15	-5	-15	-4	-11	-4	-10	-4	-10	-4	-10	-3
22	Small Power	12	11	12	11	12	11	12	11	12	11	12	11	12	11	12	11	12	11	12	11
23	Cogeneration	59	55	59	55	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
24	Northeast CTs	69	5	69	5	69	5	69	5	69	5	69	5	69	5	69	5	69	5	69	5
25	Rathdrum CTs	176	62	176	62	176	62	176	62	176	62	176	62	176	62	176	62	176	62	176	62
26	PacifiCorp Exchange	50	3	50	3	50	3	50	3	50	3	50	3	50	3	50	3	50	3	50	3
27	BPA/Avista Exchange	32	12	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
28	Entitlement & Supplemental	5	0	4	0	4	0	4	0	0	0	0	0	0	0	0	0	0	0	0	0
29	BPA Res. Exchange	0	0	0	12	47	47	47	47	47	47	47	47	47	72	149	149	149	149	149	149
30	BPA-WNP #3	82	41	82	41	82	41	82	41	82	41	82	41	82	41	82	41	82	41	82	41
31	CSPE	10	5	9	5	9	5	8	1	0	0	0	0	0	0	0	0	0	0	0	0
32	TransAlta-Centralia	200	138	200	143	200	143	200	143	0	0	0	0	0	0	0	0	0	0	0	0
33	Thermal- Kettle Falls	48	45	48	45	48	45	48	45	48	45	48	45	48	45	48	45	48	45	48	45
34	Colstrip	222	191	222	191	222	191	222	191	222	191	222	191	222	191	222	191	222	191	222	191
35	SEMPRA	0	19	0	19	0	7	0	0	0	0	0	0	0	0	0	0	0	0	0	0
36	BPA 5 yr. Purchase	115	115	115	86	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
37	Idaho Purchase	100	100	100	58	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
38	Duke Purchase	100	100	100	58	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
39	MIECO	25	25	25	25	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
40	Cinergy Services, Inc.	0	14	0	14	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
41	Energy Services, Inc.	0	50	0	25	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
42	Enron	50	50	50	25	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
43	TOTAL RESOURCES	2476	1425	2442	1267	2040	944	2039	933	1822	789	1822	785	1771	789	1874	866	1874	866	1874	861
44	SURPLUS (DEFICIT)	-395	-237	-295	-203	-46	-152	-30	-149	-287	-318	-332	-348	-430	-370	-283	-237	-342	-261	-402	-301